S T A T E O F M I C H I G A N

STATE OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the application of **Michigan Gas Utilities Corporation** for authority to increase retail natural gas rates.	))))	Case No. U-15990

NOTICE OF PROPOSAL FOR DECISION

The attached Proposal for Decision is being issued and served on all parties of record in the above matter on April 2, 2010.

Exceptions, if any, must be filed with the Michigan Public Service Commission, P.O. Box 30221, 6545 Mercantile Way, Lansing, Michigan 48909, and served on all other parties of record on or before April 16, 2010, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before April 26, 2009. **The Commission has selected this case for participation in its Paperless Electronic Filings Program. No paper documents will be required to be filed in this case.**

At the expiration of the period for filing of exceptions, an Order of the Commission will be issued in conformity with the attached Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for

Decision is reviewed by action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.

STATE OFFICE OF ADMINISTRATIVE
HEARINGS AND RULES
For the Michigan Public Service Commission

Sharon L. Feldman

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Sharon L. Feldman
Administrative Law Judge

April 2, 2010
Lansing, Michigan
dmp

STATE OF MICHIGAN

STATE OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the application of **Michigan Gas Utilities Corporation** for authority to increase retail natural gas rates.	))))	Case No. U-15990

PROPOSAL FOR DECISION

I.

PROCEDURAL HISTORY

Michigan Gas Utilities Corporation ("MGU"), a wholly-owned subsidiary of Integrys Energy Group (Integrys), initiated this case with its July 1, 2009 rate application under MCL 460.6a, as amended by 2008 PA 286. At the August 3, 2009 prehearing conference, Constellation NewEnergy—Gas Division, LLC (Constellation), was granted intervention and a schedule was established. On October 29, 2009, the Commission issued an order directing MGU to file tariffs by November 23, 2009, showing any rate changes the company proposed to self-implement.[1] The Commission further provided parties with the opportunity to respond to MGU's proposed self-implementation tariffs by December 3, 2009, and set an evidentiary hearing date of December 10, 2009, directing MGU to provide a witness to support the reasonableness of the proposed tariffs and to

[1] MCL 460.6a, as amended by 2008 PA 186, permits a utility to self-implement rate increases 6 months after a rate case filing, or the beginning of the projected test-year period chosen by the utility in its filing, which ever is later. In this case, that self-implementation date would have been January 1, 2010, but the Commission's approval of the partial settlement discussed below, with approved rates to take effect January 1, 2010, made moot the issue of self-implemented rates.

provide evidence regarding the effect of the statutory rate design option and reasonable alternatives. MGU filed the proposed tariffs in accordance with the Commission's order, and at the scheduled hearing, presented the testimony of David J. Kyto, which was bound into the record without the need for Mr. Kyto to be cross-examined.[2]

On December 7, 2009, just prior to the evidentiary hearing on self-implementation rates, MGU filed a partial settlement agreement, resolving all issues except the choice of a revenue decoupling mechanism for the utility. Staff signed the settlement agreement; Constellation NewEnergy filed a statement of non-objection. The Commission approved the partial settlement agreement in an order issued December 16, 2009.

Following the partial settlement agreement, the parties also agreed to modify the schedule to address the revenue decoupling mechanism. In accordance with the revised schedule, Staff filed testimony on December 17, 2009 and MGU filed rebuttal testimony on January 19, 2010. At the February 1, 2010 evidentiary hearing, the relevant testimony and exhibits were bound into the record without the need for the witnesses to appear.

MGU presented the direct and rebuttal testimony of Harry W. Johns and Valerie H. Grace. Ms. Grace, Manager of Gas Regulatory Services for the Regulatory Affairs Department of Integrys, explained the company's revenue decoupling proposals and responded to Staff's proposed modifications.[3] Dr. Johns, Senior Load Forecaster in the Budget & Forecast Department at Integrys, holds a Ph.D. in economics. He provided

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[2] See 2 Tr 10-30.
[3] See 3 Tr 39-67.

direct testimony explaining the company's sales forecasts for all customer classes, and rebuttal testimony addressing revenue decoupling.[4] MGU compiled the direct and rebuttal exhibits, originally filed with different exhibit numbers, into two exhibits: Exhibit A-1 contains Ms. Grace's affidavit and testimony as well as Schedules G-1 through G-5; and Exhibit A-2 contains Dr. John's affidavit and testimony as well as the schedules that were originally prefiled as Exhibit A-5 and Exhibit A-15. Staff presented the testimony of Robert G. Ozar, who recommended modifications to MGU's preferred revenue decoupling mechanism, as discussed below.[5]

In accordance with the revised schedule, Staff and MGU filed initial briefs on February 17, 2010, and MGU filed a reply brief on March 2, 2010. Constellation did not file briefs; Staff did not file a reply brief. The evidentiary record consists of the 73 pages of transcribed testimony in Volume 3, and Exhibits A-1 and A-2.

An overview of the issues in dispute between the parties is presented in section II below; each of the issues is examined in greater detail in the discussion in section III.

II.

OVERVIEW OF THE ISSUES

Section 89(6) of 2008 PA 295 ("§ 89(6)") expressly directs the Commission to establish a revenue decoupling mechanism for a gas utility as follows:

> **The commission shall authorize a natural gas provider that spends a minimum of 0.5% of total natural gas retail sales revenues, including natural gas commodity costs, in a year on commission-approved energy optimization programs to implement a symmetrical revenue**

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[4] See 3 Tr 68-87.
[5] See 3 Tr 88-102.

> **decoupling true-up mechanism** that **adjusts for sales volumes that are above or below the projected levels that were used to determine the revenue requirement authorized in the natural gas provider's most recent rate case.** In determining the symmetrical revenue decoupling true-up mechanism utilized for each provider, **the commission shall give deference to the proposed mechanism submitted by the provider. The commission may approve an alternative mechanism if the commission determines that the alternative mechanism is reasonable and prudent.** The commission shall authorize the natural gas provider to decouple rates regardless of whether the natural gas provider's energy optimization programs are administered by the provider or an independent energy optimization program administrator under section 91.[6]

Because this is a relatively recent statute, the Commission has not yet issued a decision implementing a revenue decoupling mechanism for a gas utility. The Commission has previously adopted revenue decoupling mechanisms for two electric utilities, Consumers Energy and Detroit Edison. In its November 2, 2009 decision in Case No. U-15645, addressing electric rates for Consumers Energy, the Commission explained the purpose of revenue decoupling:

> A decoupling mechanism is typically created as a solution to further the public policy objectives of assisting customers to use energy more efficiently and reduce the utility's reliance on certain existing fuel sources, while reducing overall costs. The principal purpose of decoupling is to transform the current regulatory paradigm that gives a utility a strong incentive to sell as much electricity as possible, without regard to the negative effects upon overall costs and individual customer bills. Decoupling can be utilized to manage changes in electricity sales attributable to updated building codes, expanded energy efficiency programs (including federal and state weatherization programs), upgrades in appliance efficiency, and other similar demand side policies.
>
> Decoupling is a ratemaking mechanism that removes the link between energy sales, or throughput, and the utility's non-fuel revenues. With decoupling, differences between projected and actual sales, and the associated differences in the utility's revenues, are reconciled periodically. A well-crafted decoupling mechanism will likely mean that

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[6] MCL 460.1089(6) (emphasis added).

> changes in revenue resulting from changes in consumption will no longer cause a utility to file a general rate case. Rather, a utility's need to file a general rate case will be driven by changes in the utility's underlying costs.[7]

Both MGU and Staff agree that a revenue decoupling mechanism is appropriate for MGU. As quoted above, § 89(6) provides for a "symmetric revenue decoupling true-up mechanism" for gas utilities that spend a minimum of 0.5% of total natural gas retail sales revenues annually on commission-approved energy optimization programs. Both MGU and Staff witnesses testified that MGU meets this spending requirement.[8] Both MGU and Staff also agree that § 89(6) of PA 295 provides for the Commission to "give deference to" the utility's preferred revenue decoupling mechanism, but permits the Commission to adopt an alternative if it is "reasonable and prudent." MGU and Staff make differing recommendations to the Commission as to what that mechanism should be, and how it should operate.

To resolve the disputes between the parties over the revenue decoupling mechanism, it is appropriate to begin with a review of MGU's proposals, followed by an overview of Staff's four proposed modifications to MGU's preferred mechanism.

A. <u>MGU's Proposals</u>

MGU proposes two alternative revenue decoupling mechanisms. Its preferred mechanism, labeled the "RDM", is modeled on the revenue decoupling mechanism approved for Consumers Energy and Detroit Edison electric rates. Under MGU's RDM, an annual reconciliation would determine for each covered rate group the revenue gain

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[7] Order, pages 51-52.
[8] See Ozar, 3 Tr 90; Grace, 3 Tr 44.

or shortfall associated with the difference between average per customer sales over the reconciliation period and the average per customer sales levels used to set rates in the most recent rate case order. The annual reconciliations would be filed every March 31 for the preceding calendar year. The revenue gain or shortfall would be returned to or recovered from customers through a credit or surcharge over a 12-month period following the reconciliation.

MGU proposes to group the rate classes covered by its preferred RDM into three groups: the Residential class forms one group; the Residential Multi-family Dwelling Meter Classes I and II and Small General Service class would be grouped together because customers in these classes pay the same distribution charges; likewise, Residential Multi-family Dwelling Meter Classes III and IV would be grouped together because customers in these classes pay the same distribution charges. The Large General Service class is not covered by the company's proposal. Within each covered group, the traditional sales customers, choice customers and transportation customers would all receive the same surcharges and credits.

Schedule G1 of Exhibit A-1 shows how baseline usage and corresponding per customer revenue levels would be calculated from sales volumes, customers, and charges approved in the rate case. Schedule G2 of Exhibit A-1 illustrates the operation of the MGU-preferred RDM, first assuming an increase in sales (and thus distribution revenues) per customer and then assuming a decrease in sales (and thus distribution revenues) per customer.[9]

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[9] In Case Nos. U-15645 and U15768, the Commission indicated that revenue gain or shortfall would be determined by using the change in sales per customer multiplied by the number of customers over the

The company also presented an alternative revenue decoupling proposal, which it labels the "Straight Fixed Variable" or "SFV" mechanism. This mechanism would only apply to residential customers, and is based on a division of distribution costs into "fixed" and "variable". Since most (98%) of the distribution costs assigned to residential sales customers are considered "fixed" costs, Ms. Grace testified, the company proposes to recover those costs through the monthly customer charge, i.e. without regard to the volumes of gas used by the customers. Schedule G3 of Exhibit A-1 shows the breakdown of distribution costs between fixed and variable; Schedule G4 shows a derivation of the resulting monthly customer charge for residential sales customers of $24.37. For residential sales customers, the remaining 2% of distribution costs that are "variable" rather than fixed, essentially the gas acquisition costs, would continue to be recovered through a volumetric charge. The distribution costs assigned to monthly residential choice customers and aggregated transportation customers are entirely fixed costs, since the choice customers are not assigned a share of the gas acquisition costs. Under the company's SFV proposal, there would be no reconciliation of the revenues collected through the monthly customer charge using the actual volumes of gas sold.

B. Staff's Recommended Modifications

Staff recommends that the Commission adopt a modified version of the company's RDM. Mr. Ozar explained Staff's proposed modifications. Staff focuses on the Commission's characterization of the revenue decoupling mechanisms it has already approved as "pilot programs", and encourages the Commission to broaden the

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reconciliation period. Note that MGU instead proposes to use the rate case customer count. See Grace, 3 Tr 46, lines 13-16; Exhibit A-1, Schedule G2, column I.

types of revenue decoupling mechanisms it approves. Staff also notes that in its orders in these two cases, the Commission directed the parties to provide further details and analysis of the mechanisms in the respective reconciliations.

For MGU, Staff recommends that the RDM reconcile total distribution revenues based on actual sales volumes, rather than average sales per customer. As Mr. Ozar explained, using total jurisdictional distribution revenue (total sales) as the basis for the revenue decoupling mechanism is technically equivalent to the combination of the usage per customer tracker preferred by MGU plus a customer tracker. Staff also recommends that the RDM reconcile weather-normalized sales volumes over the reconciliation period to the rate case sales projections, and that the reconciliation exclude months in which the company self-implements a rate increase pursuant to MCL 460.6a. Staff further recommends that the Commission adopt a "floating" reconciliation period that would vary with the date of each new rate case order, rather than "fixing" each reconciliation period as a calendar year. Staff also offered additional recommendations if the Commission prefers a "fixed" reconciliation period.

MGU strongly objects to Staff's proposals to use weather-normalized total sales in the decoupling reconciliation and to exclude months in which the company has self-implemented a rate increase. Dr. Johns and Ms. Grace explained the company's objections to Staff's proposals in their rebuttal testimony. Dr. Johns presented an analysis of the volatility of both weather-normalized and non-normalized sales volumes, for electric and gas customers, to support his contention that weather-normalization should not be required, and identified technical difficulties he perceived in implementing Staff's proposal to use weather-normalized data. Ms. Grace explained MGU opposition to Staff's proposals to use weather-normalized total sales volumes rather than unadjusted per customer consumption as the basis for the revenue reconciliation and to exclude self-implementation months, testifying that Staff's proposals were inconsistent with the Commission's prior decisions and with § 89(6), could jeopardize the utility's ability to recover its authorized revenue requirement, and were not reasonable and prudent. While the company does not take a strong position on the reconciliation period, fixed or floating, the company does acknowledge challenges associated with either choice.

III.

DISCUSSION

In the following discussion, this PFD first considers Staff's proposed modifications to MGU's RDM. The most controversial modification is Staff's proposal to use weather-normalized sales data for the reconciliation, so this is discussed in section A; section B discusses Staff's proposal to exclude from the reconciliation months in which the company self-implemented rates; section C discusses the related question of the timing of reconciliations; section D discusses Staff's proposal to use total sales as the basis of the true-up mechanism in lieu of the company's proposal to reconcile revenues associated with per customer consumption. Next, Section E discusses the company's alternative mechanism, the SFV mechanism.

A. Weather normalization

In Cases Nos. U-15645 and U-15768, the Commission approved revenue decoupling mechanisms for Consumers Energy and Detroit Edison electric rates that will adjust the utilities' post-rate-case per-customer revenues to what they would have been had customer usage remained unchanged over the reconciliation period. The Commission's orders in these cases make clear that customer usage will not be weather normalized. Likewise, MGU's preferred RDM also uses non-weather-normalized consumption. Staff instead recommends the use of weather-normalized sales data in the decoupling mechanism.[10]

Mr. Ozar explained Staff's concern with the potential rate volatility if ratepayers rather than the utility absorb revenue changes that are weather driven.

Mr. Ozar testified that because weather-normalized sales projections are used in ratesetting, over the long term, a utility will not suffer a statistically significant gain or loss from changes in weather. But in the short term, he testified, customers would see a greater volatility in their bills if the difference between actual weather and normal weather is captured in the revenue decoupling mechanism:

> Weather trackers operate after-the-fact by reconciling actual revenues (not weather normalized) with normalized revenue requirements and deferring the difference for recovery in a future period. The Commission should be aware that this timing impact has the potential to increase the volatility of retail rates to the detriment of ratepayers. This is particularly relevant for a gas utility, since its sales levels are significantly a function of the weather.[11]

As an example, he hypothesized a warmer-than-normal year followed by a colder-than-normal year, and explained that the surcharge arising from the first year under MGU's proposed RDM would add to the higher costs faced by consumers in the following

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[10] As discussed in more detail below, Staff also proposes using total throughput volumes rather than per customer consumption. This section focuses on whether the sales data used in the reconciliation should be weather-normalized. The weather-normalization issue is the same whether total volumes or average usage are reconciled.
[11] 3 Tr 97-98.

colder year: "The end result is more dramatic swings in customer bills as compared to a decoupling mechanism that reconciles weather-normalized revenues."[12] Put another way, Mr. Ozar testified that reconciling weather-adjusted sales to non-weather-adjusted sales increases the magnitude of the revenues flowing through the revenue decoupling mechanism, thus potentially increasing retail rate volatility.

MGU opposes using weather-normalized sales data to reconcile distribution revenues on several grounds. MGU argues that weather normalization is inconsistent with the mandate of § 89(6) because it will not result in a symmetrical revenue decoupling mechanism, and is unreasonable and imprudent because it will prevent the utility from earning its authorized revenue requirement. MGU further contends that weather normalization is inconsistent with the Commission's prior orders addressing revenue decoupling, and that there is no logical distinction to be made between gas and electric utilities because both gas and electric operations are affected by weather. Additionally, MGU argues that weather normalization is complicated and Staff has failed to adequately explain how the sales data would be weather normalized. MGU relies on the testimony of both Ms. Grace and Dr. Johns to support its arguments.

To understand MGU's contention that weather normalization contravenes the symmetry requirement of section 89(6), it is helpful to review MGU's testimony as to how the company's weather-normalized sales forecasts were prepared. Dr. Johns testified that the company used regression analysis with the assistance of a statistical software package (Metrix ND). Monthly historical data for the period November 1997 through 2009 were used to forecast the 2009-2014 period. He explained the weather-

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[12] 3 Tr 98.

normalization models used, as well as other variables used to project the "use per customer" and "customers" for each customer class. He further explained that for the residential, multi-family and small general service sectors, weather-normalized per customer usage is projected to decline for the forecast horizon (through 2014) primarily due to ongoing efficiency trends and the weak economic conditions in MGU's territory.[13]

In her rebuttal testimony, Ms. Grace testified:

> As the Act [§ 89(6)] calls for a <u>symmetrical</u> revenue decoupling mechanism, it anticipates that future sales revenues will be higher or lower than those approved by the Commission. However, taken collectively, the items that Mr. Ozar chose to focus on all point to declining sales revenue, or revenue shortfalls. Energy efficiency induced losses, combined with weather normalized sales losses projected by MGUC, would result only in charges to customers, an asymmetrical result.[14]

That is, if MGU has correctly forecast declining use per customer on a weather - normalized basis, over time, all else equal, actual weather-normalized sales per customer will fall below the rate case projected sales, resulting in charges to customers rather than credits.

MGU also relies heavily on the Commission's decisions in Case Nos. U-15645 and U-15768, contending the Commission's decisions make clear "actual" not weather-adjusted sales data should be used. The Commission's November 2, 2009 order in Case No. U-15645, e.g., describes decoupling as a reconciliation of "differences between projected and actual sales, and the associated differences in the utilities' revenues." To MGU, the Commission's use of "actual sales" in this order and similarly in Case No. U-15768 shows that actual sales rather than weather normalized sales are

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[13] See 3 Tr 72-78.
[14] See 3 Tr 61 (emphasis in original).

consistent with the intent of revenue decoupling. In its reply brief, MGU argues that only when non-normalized sales are used is the link between utility revenues and throughput broken.

In arguing that there is no rational basis to treat MGU differently than Consumers Energy and Detroit Edison because it is a gas utility, MGU disputes Staff's claim that gas utility sales are more weather-dependant than electric utility sales. Dr. Johns testified in rebuttal that both electric and gas sales are highly volatile. He presented an analysis in his Schedules E3 and E4 of Exhibit A-2, showing various statistical measures of the variability of both monthly electric sales and monthly gas sales. Pages 1 and 2 of Schedule E3 show actual and weather-normalized monthly sales data for Wisconsin Public Service Corporation's (WPSC's) electric utility operations from 2002 through 2009, and summary statistics. Pages 3 and 4 present comparable data for WPSC's gas utility operations. Schedule E4 presents MGU sales data for the period 2000 to 2009, with a chart reflecting heating degree data over a longer period, 1963 to 2007. From his analysis, Dr. Johns concluded that actual and weather normalized sales varied widely on a monthly and annual basis, for both gas and electric utilities. He testified that WPSC's weather-normalized residential electric sales variance was three times that of WPSC's gas operations, and concluded that weather and related rate volatility affecting a gas utility can be significantly less than that affecting an electric utility.[15]

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[15]See 3 Tr 85.

MGU's contention that a weather-normalization adjustment is unreasonable and imprudent is also based on Dr. Johns's analysis.[16] From the longer series of heating degree day data shown in the chart on page 3 of Schedule E4, Mr. Johns identifies a warming trend. He presents MGU's actual annual heating degree days over the time period on one line, and in comparison, 10-year and 30-year rolling averages. He testified that in 12 out of the last 15 years, MGU's actual sales were below the 30-year average weather-normalized sales, and that MGU would not have recovered its revenue requirement during this period using weather-normalized sales. Ms. Grace amplified on this argument, further testifying that it would be unreasonable to ask MGU to decouple its rates over a 30-year weather-normalization period.[17]

Dr. Johns also testified that weather normalization is complex, and that important details were missing from Staff's analysis. He and Ms. Grace opined that the result would be contentious reconciliations as the parties debate how the weather normalization should be made.[18]

This PFD recommends use of weather-normalized sales data in any true-up proceeding under § 89(6). Staff's analysis is persuasive that gas utility sales are highly dependant on weather, and that if unadjusted sales data are used in the reconciliation, the resulting rate volatility could adversely affect ratepayers. While MGU claims that weather causes sales volatility for electric utilities as well as gas utilities, MGU's analysis does not refute Staff's testimony that gas utility sales are particularly a function of the weather. Instead, MGU's volatility analysis simply captures the month-to-month

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[16] See 3 Tr 85-86.
[17] See 3 Tr 62-63.
[18] See Johns, 3 Tr 86-87; Grace 3 Tr 66-67.

or seasonal volatility that undisputedly exists. Consumption will be significantly higher in January than August whether actual sales or weather-normalized sales are used, and those differences generate a month-to-month variation. Dr. Johns himself explained this volatility in his direct testimony, explaining that monthly binary values are used in the modeling to account for seasonality.[19] Measuring the variation in sales from month to month does not measure the extent to which weather explains the difference in usage from year to year, or from one January to the next.

Addressing the remaining arguments made by MGU, neither § 89(6) nor the Commission's prior decisions require the use of entirely unadjusted sales as the basis of a revenue decoupling mechanism. Section 89(6) recognizes that there can be a choice of mechanisms, i.e. that the legislature was not imposing a requirement as to how revenue decoupling would take place, but allowing the Commission to determine a reasonable and prudent mechanism. In rejecting Detroit Edison's request to use weather-adjusted total sales, the Commission instead chose in Case No. U-15768 to use sales per customer, i.e. sales adjusted by customer count but not by weather. MGU's argument that "actual" sales must be used in a revenue decoupling mechanism is inconsistent with its own preference to adjust "actual sales" by the customer count to derive the consumption per customer as the base for its RDM.

A weather-normalization adjustment also does not contravene the specification in § 89(6) for a "symmetrical" revenue decoupling mechanism. The symmetry called for is satisfied by a mechanism that can result in credits or surcharges if the underlying rate

[19] See Johns, 3 Tr 72-78.

case projections prove erroneous. MGU's usage projections are based on regression models, which by their nature may understate or overstate actual consumption.[20]

MGU's claim that the use of weather-normalized rather than actual sales will prevent it from earning its authorized rate of return also is not dispositive. As the Commission recognized in rejecting Detroit Edison's request to reconcile actual sales rather than consumption in its revenue decoupling mechanism, the purpose of the revenue decoupling mechanism is not to ensure that the utility is compensated for all potential loss, but to remove the disincentive to the utility to having its customers be more efficient.[21] Moreover, to the extent MGU's argument is based on a concern that over time, real weather will increasingly be warmer than the company's weather-normalized projections, this concern should be addressed in a subsequent rate case, where the appropriate methodology for weather normalization can be evaluated.

Nor is weather normalization inconsistent with the concept of a revenue decoupling mechanism as a means to break the link between utility revenues and sales levels, to remove the utility's disincentive to promote energy efficiency. Using weather-normalized sales in the revenue decoupling mechanism would allow the utility to retain per customer revenues above rate case levels only if the increased usage generating those revenues was attributable to colder-than-normal weather; the utility would not benefit from less efficient customer usage. Likewise, the utility would be able to recover for decreases in per customer revenues not attributable to weather, including decreases caused by greater efficiency.

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[20] See Johns, 3 Tr 71-77.
[21] See January 11, 2010 Order, Case No. U-15768, page 65.

Finally, the potential complexity of weather normalization is not an obstacle to the adjustment proposed by Staff. Since the rate case projections are based on weather-normalized data, and since Dr. Johns explained the modeling used to weather-normalize MGU's prior sales data,[22] and further presented weather-normalized sales data for MGU for the period 1963 through 2007, the Commission should make clear that the weather normalization used in the reconciliation should mirror as closely as possible the weather normalization model used to make the underlying sales projections.

B. <u>Self-implemented Rates</u>

Staff also recommended that the RDM exclude months in which the company self-implements rate increases pursuant to MCL 460.6a. Mr. Ozar noted that the decision to self-implement new rates is under the control of the utility, and testified: "[I]t would seem unjust to 'double dip' customers by allowing for the unilateral increase in rates by a utility and to provide for a true-up of actual sales revenues during such self-implementation months."[23]

MGU contends that the Commission authorized Consumers Energy and Detroit Edison to include self-implementation months in its annual reconciliations, and that the Commission would not have permitted this if it resulted in "double dipping." Ms. Grace testified in rebuttal:

> [I]ncluding self-implemented months in the annual reconciliation would not result in double dipping or a unilateral increase in rates. Including self-implemented months in the annual reconciliation would merely allow a true-up of actual revenues arising from the self-implemented rates and

[22] See Johns, 3 Tr 73-75.
[23] 3 Tr 99.

> actual sales volumes with those revenues arising from final rates and sales approved by the Commission.[24]

The parties acknowledge that in its decision in Case No. U-15645, the Commission excluded from the mechanism the time period prior to the final order during which Consumers Energy had self-implemented rate increases. The same limitation was established in Case No. U-15768. In these cases, however, the Commission left open the question of whether future periods of self-implementation would be included in the true-up for the mechanisms established in those cases. The Commission's January 11, 2010 order in Case No. U-15768 directs Detroit Edison as follows:

> In the event Detroit Edison has filed a new rate case and self-implemented new rates in the 12-month period, the utility shall include a very detailed proposal with specific explanation as to how self-implementation fits with the decoupling mechanism and proposed reconciliation.[25]

Since the parties have raised and briefed this question in this case for MGU, however, it is appropriate that this PFD make a recommendation as to how periods of self-implementation be handled under the revenue decoupling mechanism established in this proceeding.

First, § 89(6) provides that a revenue decoupling true-up adjust for "sales volumes that are above or below the projected levels that were used to determine the revenue requirement authorized in the natural gas provider's most recent rate case." As the Commission recognized in Case No. U-15645, it is not appropriate to attempt to reconcile revenues from a period prior to a final rate case order using a revenue

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[24] See 3 Tr 59.
[25] See Order at page 68; see also the November 2, 2009 order in Case No. U-15645 at page 54.

decoupling mechanism established in that final rate case order. Any revenue decoupling true-up should instead by statute relate to the sales volumes approved in the most recent (i.e. prior) rate case. Moreover, rates self-implemented during that pre-order time period are already reconciled, per MCL 460.6a, to the revenues authorized in the final rate case order.

Looking forward, consider the situation where a revenue decoupling mechanism is already in effect pursuant to a final rate case order, and a utility files a new rate case application and then self-implements a rate increase. Again it would not be appropriate to reconcile the revenues collected during the self-implementation period based on the sales volumes approved in the prior order, because by self-implementing a rate increase, the utility has committed to the reconciliation process under MCL 460.6a, and those revenues will be reconciled to the final rate case order.

Excluding self-implementation months is also reasonable since one of the primary benefits to the utility of the self-implementation provision is that it can adjust its revenues to reflect changes in the number of customers and customer usage, i.e. throughput, along with other cost changes experienced by the utility. In choosing to take advantage of the broader self-implementation opportunity under MCL 460.6a, it is reasonable that the utility thus chooses to give up the more modest protections of a revenue decoupling mechanism for those months.

While MGU implicitly contends that the self-implementation period can be reconciled both under a revenue decoupling mechanism and under MCL 460.6a, it has provided no analysis to support this contention. Envision the revenues a utility collects under a self-implemented rate increase divided into two pieces: the first piece is the revenue the utility would have received but for the self-implemented rate increase; the second piece is the additional revenue the utility collects due to the self-implementation. If one were to attempt to reconcile the first piece revenues under an RDM using the prior rate case volumes, one would ignore that the second piece contained a more current adjustment for throughput volumes. This is why Staff labels the application of the RDM under such circumstances “double-dipping”.

For these reasons, this PFD recommends that if the Commission adopts a version of the RDM proposed by MGU, it clarify that self-implementation months will be reconciled pursuant to MCL 460.6a rather than pursuant to the revenue decoupling mechanism.

C. Fixed or Floating Reconciliation

MGU proposes an annual reconciliation for its preferred RDM, with filings made every March 31 for the prior calendar year, following the computational approach set forth in Schedules G1 and G2. Staff identifies an alternative approach to the reconciliation period, which it characterizes as “floating” rather than “fixed”.

Mr. Ozar explained that the “floating” reconciliation would start a new annual period with each new rate case filing made by the utility. He recognized that whether a fixed or floating period is used, there would still be periods shorter than a year that would need to be reconciled. He refers to these as “stub” periods and indicates that they can be carried over to the following reconciliation or that refunds or credits determined for a prior period can be extended as an approximation.

In its reply brief, MGU does not disagree that “stub” periods will occur. MGU indicates in such circumstances, the revenues should be “prorated”, although it does not indicate how this should be done.

Because the timing of the rate cases will not likely coincide exactly with each calendar year, it is likely that at least some months to be reconciled will not fall neatly within a calendar year. The recommendation made above to exclude self-implementation months adds an additional source of a rate change that would result in a “stub” period. As discussed above, the consumption patterns are highly seasonal, with low consumption in summer months and much higher consumption in winter months, both on a per-customer and aggregate basis. Therefore, an “annual” consumption per customer measure would not logically be applicable to a time period less than a full year. Mr. Ozar appropriately recognized that to reconcile a period of months short of a full year, monthly usage would need to be evaluated: “If monthly base levels have not been established for each rate class, an estimation procedure will be needed to convert annual base sales levels into specific monthly sales levels.”[26] Note that the sales and customer count projections MGU uses to project customer usage are presented on a monthly basis.[27]

Recognizing that rates set in this docket became effective for MGU on January 1, 2010, it is possible these rates will remain in effect for an entire calendar year. If so, MGU’s proposed filing date of March 31, 2011 to reconcile calendar year 2010 is reasonable. If rates are changed before the end of a calendar year, the reconciliation

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[26] See 3 Tr 94. This may be what MGU intends by the statement in its reply brief that revenues should be prorated in a shortened reconciliation period.
[27] See Exhibit A-2, Schedules E1.1 and E2 (A-5/HWJ-1).

for that “stub” period should likewise be filed within three months of the rate change. This PFD therefore recommends that reconciliations under the RDM occur at least as frequently as once per year, with MGU required to file three months after the rates set in this docket have been in effect for any calendar year, or three months after the rates are changed by self-implementation or a Commission’s final order, which ever is sooner.

In each reconciliation, the Commission will be able to determine the time period over which the revenue gain or shortfall will be recovered. Also, recognizing that the Commission may alter the RDM in future rate cases as it gains experience, it is premature to determine whether or when reconciliations arising from two different rate cases should be combined. In any subsequent rate case, the Commission will have the opportunity to establish new reconciliation filing requirements.

D. Sales or Consumption Tracking

Staff also proposes that the revenue decoupling mechanism reconcile revenues based on total sales rather than consumption (average sales per customer). Mr. Ozar explained that in its previous orders establishing revenue decoupling mechanisms, the Commission indicated it viewed the mechanisms as “pilot” programs. Staff’s brief urges the Commission to consider testing alternative mechanisms during the “pilot” phase of the implementation of revenue decoupling mechanisms for the regulated utilities:

> Staff believes that an RDM using a straight revenue algorithm (with weather normalization) may have merit compared to an RDM using a consumption-per-customer algorithm. Staff acknowledges that a consumption-per-customer RDM is sufficient with respect to energy efficiency goals of eliminating the utility throughput disincentive to promoting energy efficiency. However, if approved by the Commission, the Staff’s proposed pilot RDM would enable the Commission to evaluate

> the merits of an RDM that also reflected changes in the number of customers under real-world conditions.[28]

MGU opposes the straight revenue (sales) tracker, contending that with the addition of the "customer tracker" component, MGU would not recover the costs associated with new customers. Ms. Grace testified:

> It is necessary to determine the RDM on a per customer basis to filter out any changes (increase or decrease) in the number of customers that would differ from those levels supporting the revenues approved by the Commission in a general rate case proceeding. Doing so will not only isolate the changes in usage and related distribution revenues for the number of customers that were used to determine the revenues approved in a general rate case proceeding; it will recognize the additional costs incurred by MGUC to provide service to new customers. These costs include the addition of new services and meters as well as other expenses to serve new customers joining the system. This approach will allow MGUC to continue to recover the cost of connecting new customers. Moreover, it will also prevent MGUC from recovering revenues for load losses associated with customers leaving the system.[29]

This PFD recommends continued use of per customer revenues in the RDM. While the Commission may benefit from a variety of tracking mechanisms, it is also true that the Commission may benefit from observing how a similar mechanism works for different utilities. Staff has not responded to Ms. Grace's testimony that new customer revenues are required to offset new customer costs. Moreover, the risk of error associated with the forecast of the number of customers would be shifted to the ratepayers under Staff's proposal, and the magnitude of that risk cannot be ascertained on this record. Finally, noting that under certain circumstances, MGU's proposal does

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[28] Staff brief, pages 2-3.
[29] See Grace, 3 Tr 47.

provide for some partial recovery of revenues associated with load loss,[30] there is no suggestion on this record that such recovery would be material.

E. SFV Mechanism

MGU's direct case presented the SFV mechanism as an alternative revenue decoupling mechanism. As explained above, the SFV would allow MGU to recover its fixed costs through a non-volumetric monthly customer charge. In briefing the revenue decoupling issue, neither party has provided any significant analysis of this proposal. This PFD declines to recommend that the Commission adopt the alternative SFV mechanism proposed by MGU. A review of the method shows that it does not clearly fit the statutory concept of a revenue decoupling mechanism, because there is no true-up of the related revenues. It is true that the Commission can always consider decreasing the amount of revenues flowing through a decoupling mechanism by increasing the amount of the monthly customer charge, but doing so would not provide an opportunity to "true up" forecast sales. While MGU cites as an advantage that there need be no reconciliation, it would also be the case that the lower volumetric charges might reduce customer incentives to conserve, and the magnitude of the increase in the customer charge could pose a hardship for some customers.

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[30] As explained above, MGU's RDM reconciles rate case revenue-per-customer estimates with actual revenues per customer, but determines the final amount to be refunded by multiplying the revenue-per-customer shortfall or gain by the rate case customer count assumptions. If per customer revenues fall, and MGU loses customers over the reconciliation period, MGU will recover the revenue shortfall for the higher customer count used in setting rates.

IV.

CONCLUSION

In conclusion, for the reasons set forth above, this PFD recommends that the Commission adopt the RDM proposed by MGU with two of the modifications recommended by Staff: the reconciliation should be based on weather-normalized consumption data, and should exclude months in which the utility has self-implemented a rate increase pursuant to MCL 460.6a. This PFD further recommends that MGU file for reconciliation under this RDM within 90 days of the end of each calendar year in which rates set in this docket remain in effect, or within 90 days of the date those rates are changed, either by self-implementation or Commission final order. Recognizing that reconciliations may cover time periods less than a full year, monthly per customer usage forecasts underlying the rate case projections should be used in such reconciliations.

STATE OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
For the Michigan Public Service Commission

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Administrative Law Judge

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